BIG WEST OF CALIFORNIA, LLC
A FLYING J Company
6451 Rosedale Highway • Bakersfield, CA 93308 • Phone 661.326.4200 • www.flyingj.com

Certified Mail
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December 4, 2008

Mr. Gerardo Rios
US Environmental Protection Agency, Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

Subject: **Big West of California – Clean Fuels Project – Request for Cancellation of PSD Permit Application**

Dear Gerardo:

I am writing to cancel the application for a Prevention of Significant Deterioration (PSD) preconstruction permit that was submitted by Big West of California, LLC (Big West) to EPA Region 9 for our Clean Fuels Project. Specifically, this letter requests that EPA cancel its review of the draft PSD permit for the Clean Fuels Project that EPA Region 9 issued for public comment on November 5, 2007 (see Docket Number EPA-R09-OAR-2007-0985; http://www.epa.gov/region09/air/permit/big-west/index.html). The Clean Fuels Project as originally configured, including the Alkylation Unit and dedicated cooling tower, and Fluid Catalytic Cracking Unit, was not approved by the Kern County Board of Supervisors, and therefore, cannot proceed. Instead, the Board approved a variation of the Clean Fuels Project referred to in the Environmental Impact Report as Alternative D, a markedly reduced project.

As we discussed with you and your colleagues earlier this month, Alternative D does not trigger review under the EPA Prevention of Significant Deterioration (PSD) program, as emissions of PSD pollutants are below EPA PSD significant increase thresholds. While this information has been submitted directly to the San Joaquin Valley Air Pollution Control District[1], we thought it would be helpful for you to receive this information directly. Please note that this letter does not constitute a formal request for an applicability determination under the PSD program. Our analysis of the potential to emit for Alternative D relative to applicable PSD thresholds is set forth below, which consists of a brief summary of Alternative D, annual emission totals as compared to PSD significant increase thresholds, and attachments that provide the full basis for the potential to emit calculations.

[1] In our letter to the District, we also provide our analysis of why Alternative D does not trigger review under EPA's $PM_{2.5}$ New Source Review final rulemaking, issued May 16, 2008.

Potential to Emit - Alternative D

On October 21, 2008, the Kern County Board of Supervisors certified the Environmental Impact Report under the California Environmental Quality Act (CEQA) and granted its approval for Alternative D to the Big West Clean Fuels Project, which consists of the following:

- 30,000 barrel per day (BPD) Vacuum Gas Oil Hydro Desulfurization Unit, with associated 35 and 47 MMBtu/hr heaters (VGO HDS)
- 641 MMBtu/hr Hydrogen Unit (HGU2)
- 120 MMBtu/hr Hydrocracker Unit (HCU)
- 1,200 BPD Sour Water Ammonia to Ammonium ThioSulfate Unit (SWAATS)
- LPG Merox Treatment Unit
- Ground flare with flare gas recovery
- 15,000 gallon/minute process cooling tower
- Three 525 hp emergency diesel-powered firewater pumps

By letter dated October 31, 2008 from Big West to the San Joaquin Valley Air Pollution Control District, Big West cancelled the applications for the Fluid Catalytic Cracking Unit, the Alkylation Unit, and the cooling tower associated with the alkylation unit, as these three units are not included in Alternative D. Therefore, the potential to emit for Alternative D does not include emissions from these three units.

The potential to emit for Alternative D is summarized and compared to applicable PSD permitting thresholds in Table 1, below:

Table 1
Big West of California – Clean Fuels Project – Alternative D
Potential to Emit

Pollutant	Annual Emissions (TPY)	PSD Threshold (TPY)
Carbon monoxide	62	100
Nitrogen oxides	25	40
Sulfur oxides	29	40
Particulate matter/$PM_{2.5}$ (filterable fraction only)	8	25
Lead	0.002	0.6
Fluorides	0	3
Sulfuric Acid Mist	Negligible	7
H_2S	0.17	10
Total Reduced Sulfur	0.17	10
Reduced Sulfur Compounds	0.17	10

Attachment A and the associated Excel spreadsheet provide the equations, maximum capacities, engineering bases, and other assumptions used in the potential emission calculations. Both Attachment A and the Excel spreadsheet are included in the attached CD. As indicated in Attachment A, all particulate matter emitted from Alternative D components is $PM_{2.5}$. Construction and operation of Alternative D will have no affect on emissions from existing combustion units within Areas 1 and 2 and Area 3.

PSD Applicability Analysis

As demonstrated in Table 1, above, emissions of pollutants from Alternative D are below the applicable PSD significance thresholds. Further, construction of Alternative D will have no affect on existing combustion units within Areas 1 and 2 and Area 3. Therefore, no PSD permit is required for Alternative D. Further, there is no need to incorporate a synthetic minor emissions limit in the Authority to Construct for the HCU, as the potentials to emit for all PSD pollutants are below PSD thresholds.

If you have any questions regarding this application, please contact Mr. Bill Chadick (661.326.4412) or Mr. Everard Ashworth at ALG (805.764.6017).

Sincerely,

Eugene Cotten

Eugene Cotten
Vice President Refining
Refinery Manager
Big West of California, LLC

Enclosures

cc: Mr. Leonard Scandura, SJVAPCD

725,402
V:ehs/private/cfp/psd/psd permit ltr

Attachment A

Big West of California Clean Fuels Project – Alternative D

Potential Emissions Estimate

This document details the calculations and assumptions that have been used in estimating potential emissions of criteria PSD pollutants from the Bakersfield Refinery Clean Fuels Project – Alternative D, and that have been used in estimating potential emissions of $PM_{2.5}$

Process Heaters

Potential emissions from the process heaters (35 MMBtu/hr and 47 MMBtu/hr heaters in the VGO-HDS; 641 MMBtu/hr reformer furnace; and 120 MMBtu/hr hydrocracker heater) are calculated using the permitted emission limits and the maximum rated heat input capacity. It is assumed that the combustion units operate continuously (8760 hours per year).

NOx and CO Emissions

Exhaust concentrations of NOx and CO from process heaters are based on the level of control established as BACT for refinery fuel gas combustion. These concentrations are summarized in the table below, and will be federally enforceable limits in the facility's Title V permit:

Unit Type	NOx Conc. (ppmv @ 3% O_2)	CO Conc. (ppmv @ 3% O_2)
Heaters, <50 MMBtu/hr	5 ppmv	50 ppmv
Heaters, ≥50 MMBtu/hr	5 ppmv	10 ppmv

NOx and CO emissions are calculated in accordance with EPA Method 19 (40 CFR Part 60, Appendix A, Method 19, §2.1) as follows:

$$EF = Conc \times CF \times F_d \times \left(\frac{20.9}{20.9 - \%O_2} \right), \text{ where}$$

EF = Emission factor, lb/MMBtu

Conc = Pollutant concentration, ppmv (see above table)

CF = Method 19 factor to convert ppmv to lb/scf

$CF_{NOx} = 1.194 \text{ H } 10^{-7}$

$$CF_{CO} = CF_{NOx} \times \frac{MW_{CO}}{MW_{NOx}} = 7.270 \times 10^{-8}$$

F_d = F-factor for natural gas = 8,710 scf/MMBtu

$\%O_2$ = 3% O_2 for combustion devices

The calculated lb/MMBtu emission factors and the rated HHV burner capacity are used to calculate the annual potential emissions as follows:

Emissions (tpy) = EF (lb/MMBtu) H Rating (MMBtu/hr) H (8760 hr/yr) / (2000 lb/ton)

SO_2 Emissions

SO_2 emissions are calculated based on the sulfur content of the fuel gas, assuming that all sulfur in the fuel gas is converted to SO_2. The refinery fuel gas will have a federally enforceable concentration limit of 40 ppmv total reduced sulfur (4-hour average).

The emission factor calculation is:

$$EF = \left(\frac{Conc_{FG}}{10^6}\right) \times \frac{MW_{SO_2}}{V} \times \frac{10^6\,Btu/MMBtu}{HHV}$$, where

EF = Emission factor, lb/MMBtu

$Conc_{FG}$ = Fuel gas sulfur concentration, ppmv (40 ppmv)

MW_{SO2} = SO_2 molecular weight (64.0588 lb/lb-mol)

V = Specific volume based on ideal gas equation (379.4 scf/lb-mol)

HHV = Higher heating value of refinery fuel gas, Btu/scf

As with NOx and CO, once the lb/MMBtu emission factor for SO_2 is determined, the rated HHV burner capacity is used to calculate the annual potential emissions as follows:

Emissions (tpy) = EF (lb/MMBtu) H Rating (MMBtu/hr) H (8760 hr/yr) / (2000 lb/ton)

PM and $PM_{2.5}$ Emissions

AP-42 Table 1.4-2 (07/98) gives an emission factor for filterable particulate matter from external natural gas combustion (1.9 lb/MMscf). As directed by AP-42, this emission factor in lb/MMscf is converted to lb/MMBtu by multiplying by the higher heating value of the reference gas (1020 Btu/scf). The lb/MMBtu emission factor is multiplied by the rated HHV burner capacity to calculate the emission rate as follows:

Emissions (tpy) = EF (lb/MMBtu) H Rating (MMBtu/hr) H (8760 hr/yr) / (2000 lb/ton)

A footnote to AP-42 Table 1.4-2 indicates that all of the particulate matter from this source type is expected to be less than 1.0 μm in diameter; therefore, PM and PM2.5 emissions are equivalent.

SWAATS Unit

The SWAATS unit will emit SO_2 and CO, but not NOx or PM. Emission factors have been developed based on engineering estimates from the designers of the SWAATS unit/process.

These emission factors were provided in terms of ppmv in the exhaust gas. Annual potential emissions are calculated as follows:

$$\text{Emissions (tpy)} = \left(\frac{\text{Conc}}{10^6}\right) \times \frac{V_{Flue}}{V} \times MW \times \frac{8760\text{ hr}}{\text{yr}} \times \frac{\text{ton}}{2000\text{ lb}}, \text{ where}$$

Conc = Flue gas pollutant concentration, ppmv

V_{Flue} = Flue gas flow rate, scfh

MW = Pollutant molecular weight, lb/lb-mol

V = Specific volume based on ideal gas equation (379.4 scf/lb-mol)

Cooling Tower

PM and $PM_{2.5}$ Emissions

Particulate matter emissions from cooling towers are calculated based on the total dissolved solids (TDS) content of the water, the water circulation rate, and the drift rate (the portion of the water that exits stack as droplets). Maximum potential emissions are estimated on the basis of the maximum design circulation rate (15,000 gpm) and federally enforceable TDS limit (2000 ppm by weight). Continuous operation is assumed. Given that the particulate matter emissions from a cooling tower are based on particles present in water, all PM emissions are assumed to be filterable particulate. It is also assumed that all of the particulate matter is ≤2.5 Φm in diameter.

The $PM/PM_{2.5}$ potential emissions are calculated as follows:

$$\text{Emissions (tpy)} = \frac{\text{TDS}}{10^6} \times \rho_{water} \times D \times Q_{water} \times \frac{60\text{min}}{\text{hr}} \times \frac{8760\text{ hr}}{\text{yr}} \times \frac{\text{ton}}{2000\text{ lb}}, \text{ where}$$

TDS = Total dissolved solids, ppmw

ρ_{water} = Density of water (8.345 lb/gal)

D = Drift rate, dimensionless

Q_{water} = Water circulation rate, gal/min

Ground Flare

Emissions are calculated from the ground flare based on the continuous combustion of pilot gas plus combustion of the estimated gas volume resulting from planned and emergency startups and shutdowns of process units connected to the flare. There are no streams that are sent to the flare under normal operating conditions. The ground flare will be equipped with a flare gas recovery system, that will recover up to 500 cfm of gases sent to the flare rather than combusting them.

Flaring Event Estimates

There are four types of flaring events that have been considered in this analysis. For each type of event and each associated emission unit, engineering estimates were developed for the volume of gas that will flare and the higher heating value and sulfur content of that gas. Historical failure rates and root causes at the existing Refinery have been examined and these data have been extrapolated to reach a reasonably conservative estimate of potential emissions from emergency flaring from the CFP Alternative D project.

Event Type	# Events Per Year Included	Discussion
Pilot gas	8760 hours	Pilot gas is necessary continuous combustion. Purge gases are recovered rather than combusted. No other streams go to the flare under normal operating conditions.
Planned startups and shutdowns (SU/SD)	1 per unit	Planned SU/SD will occur only during turnarounds, once every 3-5 years. Flaring emissions based on engineering analysis of planned startup and shutdown procedures.
Emergency shutdown: Plant-wide power failure	2	At the existing refinery, there has been an average of about one plant-wide power failure per year in recent years. The Refinery is working with the electric utility to improve the reliability of the power supply. For each plant-wide power failure shutdown, emissions from a "planned startup" have also been included to account for flaring during the subsequent restart of the equipment.
Emergency shutdown: Local failure	2 per unit	Flaring/shutdown due to local mechanical or power failures happen infrequently at the existing Refinery. In addition, the equipment for CFP-Alternative D will be new and less prone to failure, and the CFP-Alternative D electrical system will be better protected and more robust than the electrical system in the existing Refinery. These factors should limit flaring due to local failure. For each local failure event, emissions from a "planned startup" have also been included to account for flaring during the subsequent restart of the equipment.

<u>NOx, CO, PM and $PM_{2.5}$ Emissions</u>

Potential emission calculations for NOx, CO, and $PM/PM_{2.5}$ use the flaring emission factors from SJVAPCD Policy FYI-83 (see Attachment 1). These emission factors are based on AP-42 emission factors. BACT and non-BACT PM emission factors are provided in FYI-83 (0.008 and 0.026 lb/MMBtu, respectively); the higher non-BACT PM emission factor is used in this analysis to provide a conservative estimate of emissions for purposes of determining PSD applicability. As with natural gas external combustion, it is assumed that all particulate matter is $PM_{2.5}$. Because FYI-83 and AP-42 Chapter 13 do not separately address filterable and condensable particulate emissions, it is conservatively assumed here that all particulate matter is filterable. (If the filterable fraction were assumed to be similar to that of external natural gas combustion as given in AP-42 Table 1.4-2, this PM emission factor would be reduced by about 75%.)

The annual potential emissions calculations are based on the continuous combustion of pilot gas and the various planned and emergency flaring events as follows:

$$\text{Emissions (tpy)} = \text{EF H}\left[\left(\text{Rating}\times\frac{8760\text{ hr}}{\text{yr}}\right)_{Pilot} + \sum_i \left(n_i \times \text{FlareVol}_i \times \text{HHV}_i\right)\right]\times\frac{\text{ton}}{2000\text{ lb}},$$

where

EF = FYI-83 emission factor, lb/MMBtu

Rating = HHV burner rating for pilot, MMBtu/hr

n_i = Number of events of type *i* per year

FlareVol_i = MMscf flared per event of type *i*

HHV_i = MMBtu/MMscf of gas flared in event of type *i*

<u>SO_2 Emissions</u>

As with heaters and boilers, SO_2 emissions from the flare pilots are calculated based on the sulfur content of refinery fuel gas (40 ppmv limit), assuming that all sulfur is converted to SO_2. The sulfur content of gases combusted as part of emergency and planned startup and shutdown operations have been estimated by the engineering firms involved in the design of the units. As with the pilot gas, all sulfur in these startup and shutdown gases is assumed to be converted to SO_2. Where sulfur content is estimated in terms of ppmv sulfur in the flared gas, SO_2 emissions are estimated as follows:

$$\text{Emissions (tpy)} = \left(\frac{\text{Conc S}}{10^6}\right)\times\frac{MW_{SO_2}}{V}\times\text{FlareVol}\times\frac{\text{ton}}{2000\text{ lb}},\text{ where}$$

EF = Emission factor, lb/MMBtu

Conc_{FG}= Fuel gas sulfur concentration, ppmv (40 ppmv)

MW_{SO2} = SO_2 molecular weight (64.0588 lb/lb-mol)

V = Specific volume based on ideal gas equation (379.4 scf/lb-mol)

HHV = Higher heating value of refinery fuel gas, Btu/scf

FlareVol = Volume of gas flared, MMscf/yr

Where sulfur is estimated in terms of pounds sulfur in the flared gas, SO_2 emissions are estimated by simply converting that sulfur to the equivalent amount of SO_2 as follows:

$$\text{Emissions (tpy)} = (\text{lb S})\times\frac{MW_{SO_2}}{MW_S}\times\frac{\text{ton}}{2000\text{ lb}}$$

Diesel I.C. Engine Firewater Pumps

NOx Emissions

The diesel fire pumps will need to meet at least Tier 2 standards when acquired, according to the California Code of Regulations, Title 17, Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) Engines. Tier 2 engines must meet a NOx+NMHC standard of 4.8 g/bhp-hr, CO standard of 2.6 g/bhp-hr, and PM standard of 0.15 g/bhp-hr.

To determine a NOx emission factor from the NOx+NMHC standard, the relative proportions of the AP-42 NOx and VOC emission factors for diesel internal combustion engines (Table 3.3-1, 10/96) were applied to the Tier 2 standard, as follows:

$$EF_{NOx} = \left(\frac{EF_{NOx}}{EF_{NOx} + EF_{VOC}} \right)_{AP-42} \times \frac{4.8\,g}{bhp-hr} \times \frac{lb}{453.59\,g}$$

The result is that about 92.5% of the 4.8 g/bhp-hr NOx+NMHC standard is attributed to NOx and about 7.5% is attributed to VOC.

The lb/bhp-hr emission factor was used to calculate the hourly emission rate based on the maximum engine horsepower:

Emissions (lb/hr) = EF H HP , where

EF = Emission factor, lb/bhp-hr

HP = Horsepower rating of engine

Non-emergency use of these engines will be limited by the Stationary CI Engine ATCM to the number of hours necessary to comply with the testing requirements of National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition. These tests are expected to take on the order of 0.5 hour per week, or approximately 30 hours per year; a federally enforceable permit condition will also limit non-emergency operation to not more than 100 hours per year.

The annual potential to emit calculation has assumed that the engines operate a total of 100 hours per year:

Emissions (lb/yr) = Emissions (lb/hr) H (100 hr/yr)

Note that the emissions from these engines is not large in comparison to the PSD applicability thresholds; assuming 200 or 300 hours or operation per year (emergency and non-emergency) would not cause the potential to emit of any PSD pollutant to exceed the relevant significance thresholds.

SO_2 Emissions

The SO_2 emission factor is based on fuel sulfur content (ULSD, or 15 ppmw S), as follows:

$$\text{EF (g/bhp-hr)} = \rho \frac{\text{lb}}{\text{gal}} \times \frac{15}{10^6} \text{S} \times \frac{MW_{SO_2}}{MW_S} \times \frac{453.6\ \text{g/lb}}{\text{HP}}, \text{ where}$$

ρ = Density of diesel fuel, 7.1 lb/gal

MW_{SO2} = Molecular weight of SO_2, 64 lb/lb-mol

MW_S = Molecular weight of sulfur, 32 lb/lb-mol

HP = Horsepower rating of engine

This g/bhp-hr emission factor was used to calculate the hourly emission rate based on the engine horsepower. As described in the NOx calculation section above, annual potential emissions were calculated on the basis of 100 hours of operation (emergency and non-emergency).

Emissions (lb/hr) = EF H HP / (453.59 g/lb), where
EF = Emission factor, g/bhp-hr
HP = Horsepower rating of engine
Emissions (lb/yr) = Emissions (lb/hr) H (100 hr/yr)

CO, PM, and $PM_{2.5}$ Emissions

Tier 2 CO and PM standards for 525 hp engines (2.6 g/bhp-hr and 0.15 g/bhp-hr, respectively) were used to calculate potential emissions. As described in the NOx calculation section above, annual potential emissions were calculated on the basis of 100 hours of operation (emergency and non-emergency). It was assumed that all PM emissions are filterable particulate emissions. A footnote to AP-42 Table 3.3-1 indicates that all of the particulate matter from this source type is expected to be less than 1.0 μm in diameter; therefore, PM and PM2.5 emissions are the same.

As with NOx and SO_2, the g/bhp-hr emission factors were used to calculate the hourly emission rate based on the engine horsepower, and annual potential emissions were calculated on the basis of 100 hours of operation per year.

Emissions (lb/hr) = EF H HP / (453.59 g/lb), where
EF = Emission factor, g/bhp-hr
HP = Horsepower rating of engine
Emissions (lb/yr) = Emissions (lb/hr) H (100 hr/yr)

Non-Criteria PSD Pollutant Project Emissions

Big West submitted a letter to EPA on October 8, 2007 addressing emissions of non-criteria PSD pollutants from the Clean Fuels Project. The list below summarizes how that letter addressed each non-criteria PSD pollutant and notes any changes resulting from the switch to Alternative D. Potential emissions of all of these non-criteria PSD pollutants are below the PSD thresholds as summarized in Table 2, and explained further below.

- **Lead:** The only sources of lead from the CFP were the combustion units. Potential lead emissions from the CFP were close to two orders of magnitude below the PSD threshold of 0.6 tpy. Given that the total combustion capacity of the project decreases under Alternative D compared to the CFP, potential lead emissions are also lower.

- **Fluorides:** There were no sources of emissions of fluorides under the CFP, nor are there any from Alternative D.

- **Sulfuric acid mist:** Based upon EPA guidance and the stack temperature of the combustion units, no emissions of sulfuric acid mist were expected from the CFP. Similarly, no emissions of sulfuric acid mist are expected from Alternative D.

- **Hydrogen sulfide (H_2S):** The sources of H_2S emissions from the CFP were the FCCU and fugitive component emissions. The FCCU will not be built under Alternative D, and that one emission unit contributed approximately 88% of the potential H_2S emission from the CFP. Potential H_2S emissions will decrease under Alternative D.

- **Total reduced sulfur (including H_2S, methyl mercaptans, dimethyl sulfide, and dimethyl disulfide):** Although it was difficult to estimate potential emissions of methyl mercaptans, dimethyl sulfide, or dimethyl disulfide, because these emissions were expected to be very small, and because potential H_2S emissions were significantly below the PSD threshold, Big West was confident that emissions of reduced sulfur from the CFP would be well below the PSD threshold. This is also the case with Alternative D.

- **Reduced sulfur compounds (including H_2S, COS, and CS_2):** The sources of reduced sulfur compounds from the CFP were the FCCU regenerator stack and fugitive H_2S emissions as discussed above. Under Alternative D, the FCCU will not be built, and fugitive emissions of H_2S will decrease.

- **Municipal waste combustor organics, municipal waste combustor metals, municipal waste combustor acid gases, and municipal solid waste landfill emissions:** Not applicable to the CFP or to Alternative D.

ATTACHMENT 1

SJVAPCD POLICY FYI-83

USE OF AP-42 SECTION 13.5 EMISSION FACTORS FOR INDUSTRIAL FLARES

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

DATE: December 11, 2002

TO: Permit Services Staff

FROM: Seyed Sadredin, Director of Permit Services

SUBJECT: Use of AP-42 Section 13.5 Emission Factors for Industrial Flares

EPA AP-42 section 13.5 Industrial Flares (9/91) provides emission factors for industrial flares. The VOC, PM10, NOX, CO, and SOx emission factors in Section 13.5 shall be used for flares located at oil exploration and production operations, refineries, chemical plants, gas plants, and other petroleum related industries. Use of these emission factors is not required, nor prohibited, for flares used in other industries by this guidance and shall be determined on a case-by-case basis.

In 2001 we received comments from EPA concerning the appropriate emission factors to use for flares. These comments and further communications with EPA resulted in the District agreeing to using the hydrocarbon emissions factor in AP-42 Section 13.5 for quantifying expected VOC emissions from flares without any correction for the non-VOC fraction of the gas being flared. However, AP-42 Section 13.5 does provide for adjustment of the total hydrocarbon (THC) emissions factor to a VOC emissions factor based on the exhaust gas speciation data in Table 13.5.2. Using this speciation data, the VOC emission factor is 0.063 lb/MM Btu. (Note that no correction for the flare gas VOC content is allowed.)

AP-42 Section 13.5 indicates 0 micrograms of soot per liter of exhaust for smokeless flares and 40 micrograms of soot per liter of exhaust for lightly smoking flares. For flares subject to BACT for PM10 (typically a visible emission limit of less than ¼ Ringelmann or less than 5% opacity, except for three minutes in any hour), a PM10 emissions factor of 0.008 lb/MM Btu will be used. This emissions factor is equivalent to 10 micrograms of soot per liter of exhaust and is reasonable for flares limited to no less than 5% opacity visible emissions. For flares not subject to BACT for PM10 visible emission are limited to less than 20% opacity except for three minutes in any hour pursuant to Rule 4101 and the appropriate emission factor is 0.026 lb/MM Btu (40 grams of soot per liter of flare exhaust).

SOx emissions are determined by mass balance using the total sulfur compounds in the gas an assuming complete oxidation to SO_2.

NOx and CO emissions are determined using the AP-42 Section 13.5 NOx and CO emissions factors of 0.068 lb/MM Btu and 0.370 lb/MM Btu respectively.

AP-42 Section 13.5 Emissions Factors for Industrial Flares are summarized below:

Pollutant	**lb/MMBtu**
VOC	0.063
CO	0.370
NOx (as NO2)	0.068
PM10 (BACT)	0.008
PM10 (non-BACT)	0.026
SOx (as SO2)	mass balance

CFP Alternative D Potential Emissions, tpy

Source	tpy					
	NOx	SOx	CO	PM	PM_{10}	$PM_{2.5}$
VGO Feed Heater	1.25	1.16	7.61	0.38	0.38	0.38
VGO-HDS Fractionator Feed Heater	0.93	0.86	5.67	0.29	0.29	0.29
Hydrocracker Fractionator Reboiler	3.19	2.96	3.89	0.98	0.98	0.98
Hydrogen Plant Reformer	17.05	15.80	20.76	5.23	5.23	5.23
SWAATS Unit Stack	0.00	8.07	11.76	0.00	0.00	0.00
Cooling Tower	0.00	0.00	0.00	0.33	0.33	0.33
Diesel Firewater Pumps	0.77	0.00	0.45	0.03	0.03	0.03
Ground Flare	2.16	0.31	11.77	0.83	0.83	0.83
Total, all above	25.35	29.16	61.90	8.06	8.06	8.06
Total, excluding HCU	22.16	26.20	58.02	7.08	7.08	7.08
PSD Thresholds	40	40	100	25	NAA	NAA

Note 1: Only filterable (i.e., direct) particulate matter emissions (PM, PM10, and PM2.5) are quantified, per EPA PM2.5 NSR Implementation Rule and preamble (73 FR 28321). In the absence of clear documentation from EPA or other sources, it has been conservatively assumed that all PM emissions from the flare and the emergency diesel engines are filterable PM emissions.

Note 2: See Ground Flare potential emission calculations on next sheet for assumptions involving number, type, and composition of flaring events.

Note 3: All PM emissions from the project are expected to be in the PM2.5 size range; therefore, PM, PM_{10}, and $PM_{2.5}$ are equivalent in the context of this project.

CFP Alternative D Potential Emissions, tpy

Non-Criteria NSR/PSD Pollutants	Significance Threshold	Estimated Alt D Emissions
Lead	0.6	0.002
Fluorides	3	0
Sulfuric Acid Mist	7	Negligible
Hydrogen sulfide (H_2S)	10	0.167
Total Reduced Sulfur	10	0.167
Reduced sulfur compounds	10	0.167
Municipal waste combustor organics	3.50E-06	NA
Municipal waste combustor metals	15	NA
Municipal waste combustor acid gas	40	NA
Municipal solid waste landfills emissions	50	NA

Clean Fuels Project - Alternative D Emissions Calculations

Reference HHV (AP-42)	1,020 Btu/scf
Refinery gas HHV	1,200 Btu/scf
F-factor	8710 dscf/MMBtu
Total S content of ref. fuel gas	40 ppmv

VGO Feed Heater

Max. Firing Rate (HHV)	47 MMBtu/hr
Pollution Control Methods	SCR and low NOx burners

Component	EF				Emission Rates		
	Source	Value	Units	lb/MMBtu (HHV)	[#/hr]	[#/year]	[ton/yr]
NOx	BACT	5	ppmv	0.006	0.3	2,499.7	1.25
SOx	Mass balance	See fuel gas sulfur content		0.006	0.3	2,317.2	1.16
CO	BACT	50	ppmv	0.037	1.7	15,219.4	7.61
PM (filterable)	AP-42 Chpt. 1.4	1.9	lb/MMscf	0.002	0.1	766.9	0.38

VGO-HDS Fractionator Feed Heater

Max. Firing Rate (HHV)	35 MMBtu/hr
Pollution Control Methods	SCR and low NOx burners

Component	EF				Emission Rates		
	Source	Value	Units	lb/MMBtu (HHV)	[#/hr]	[#/year]	[ton/yr]
NOx	BACT	5	ppmv	0.006	0.2	1,861.5	0.93
SOx	Mass balance	See fuel gas sulfur content		0.006	0.2	1,725.6	0.86
CO	BACT	50	ppmv	0.037	1.3	11,333.6	5.67
PM (filterable)	AP-42 Chpt. 1.4	1.9	lb/MMscf	0.002	0.1	571.1	0.29

Hydrogen Plant Reformer

Max. Firing Rate (HHV)	641 MMBtu/hr
Pollution Control Methods	SCR and low NOx burners

Component	EF				Emission Rates		
	Source	Value	Units	lb/MMBtu (HHV)	[#/hr]	[#/year]	[ton/yr]
NOx	BACT	5	ppmv	0.006	3.9	34,091.6	17.05
SOx	Mass balance	See fuel gas sulfur content		0.006	3.6	31,602.6	15.80
CO	BACT	10	ppmv	0.007	4.7	41,513.3	20.76
PM (filterable)	AP-42 Chpt. 1.4	1.9	lb/MMscf	0.002	1.2	10,459.6	5.23

Hydrocracker Fractionator Reboiler

Max. Firing Rate (HHV)	120 MMBtu/hr
Pollution Control Methods	SCR and low NOx burners

Component	EF				Emission Rates		
	Source	Value	Units	lb/MMBtu (HHV)	[#/hr]	[#/year]	[ton/yr]
NOx	BACT	5	ppmv	0.006	0.73	6,382.2	3.19
SOx	Mass balance	See fuel gas sulfur content		0.00563	0.68	5,916.2	2.96
CO	BACT	10	ppmv	0.007	0.89	7,771.6	3.89
PM (filterable)	AP-42 Chpt. 1.4	1.9	lb/MMscf	0.002	0.22	1,958.1	0.98

Ground Flare

Estimated max annual flow	63,620 MMBtu/yr	(See "Flare PE" sheet)

Component	EF				Emission Rates		
	Source	Value	Units	lb/MMBtu (HHV)	[#/hr]	[#/year]	[ton/yr]
NOx	SJVUAPCD FYI-83	0.068	lb/MMBtu	0.068	0.49	4,326.2	2.16
SOx	Flared stream sulfur content	[redacted]			0.07	619.5	0.31
CO	SJVUAPCD FYI-83	0.37	lb/MMBtu	0.37	2.69	23,539.4	11.77
PM*	SJVUAPCD FYI-83	0.026	lb/MMBtu	0.026	0.19	1,654.1	0.83

*District Policy FYI-83 and EPA AP-42 do not break out filterable and condensable PM emission rates separately; therefore, it has been conservatively assumed that all PM emissions are filterable PM emissions.

SWAATS Unit Stack

Exhaust flow rate*	363.8 MSCFH

Component	EF				Emission Rates		
	Source	Value	Units	lb/MMBtu (HHV)	[#/hr]	[#/year]	[ton/yr]
NOx	Engineering	0	ppmv	n/a	-	-	-
SOx	Engineering	30	ppmv	n/a	1.8	16,142.5	8.07
CO	Engineering	100	ppmv	n/a	2.7	23,528.2	11.76
PM	Engineering	0	lb/MMscf	n/a	-	-	-

*Exhaust flow rate is directly proportional to amount of sulfur produced as ammonium thiosulfate product. This exhaust flow rate corresponds to the maximum design capacity of 90.2 tpd sulfur.

Diesel Firewater Pumps

Number of engines	3
Horsepower (each)	525 hp
Horsepower (total)	1,575 hp
BSFC	0.350 lb/bhp-hr
Fuel consumption rate (each)	26.8 gal/hr
Pump capacity (each)	2000-3000 gpm
Diesel heating value	137,000 Btu/gal
Diesel density	7.1 lb/gal
Diesel sulfur content	0.0015%
Max annual op. hours (each)	100
Max daily op. hours (each)	1

Component	EF			EF	Emission Rates		
	Source	Value	Units	lb/hp-hr	[#/hr]	[#/year]	[ton/yr]
NOx	Tier 2 NMHC+NOx Standard	4.44	g/bhp-hr	9.79E-03	15.42	1,541.7	0.77
SOx	Fuel sulfur content	0.00494	g/bhp-hr	1.09E-05	0.02	1.7	0.00
CO	Tier 2 Standard	2.6	g/bhp-hr	5.73E-03	9.03	902.8	0.45
PM*	Tier 2 Standard	0.15	g/bhp-hr	3.31E-04	0.52	52.1	0.03

*In the absence of clear documentation from EPA or other sources, it has been conservatively assumed that all PM emissions are filterable PM emissions.

Cooling Tower

Circulation rate	15,000 gpm
Drift rate	0.0005%

Component	EF			EF	Emission Rates		
	Source	Value	Units	lb/gal	[#/hr]	[#/year]	[ton/yr]
PM (filterable)	Engineering - TDS estimate	2000	ppm wt	8.35E-08	0.08	657.9	0.33

CFP Alternative D Flare Emissions - Continuous, Planned, and Anticipated Emergency

Flare Source	Flare Reason	MMscf	Btu/scf	MMBtu	Sulfur Amt	Sulfur Units	NOx (tpy)	SOx (tpy)	CO (tpy)	PM (tpy)
						EF (lb/MMBtu)	0.068	n/a	0.37	0.026
Pilot	Normal Operations	21.9	1200	26280	40	ppmv	0.89	0.07	4.86	0.34
VGO-HDS	Planned Startup			None			0.00	0.00	0.00	0.00
VGO-HDS	Planned Shutdown	2.08	300	624	50	lbs	0.02	0.05	0.12	0.01
HCU	Planned Startup			None			0.00	0.00	0.00	0.00
HCU	Planned Shutdown	2.08	1200	2496	25	ppmv	0.08	0.00	0.46	0.03
HGU	Planned Startup	14.28	300	4284	25	ppmv	0.15	0.03	0.79	0.06
HGU	Planned Shutdown	0.25	1200	300	25	ppmv	0.01	0.00	0.06	0.00
HCU (Sat Gas Plant)	Planned Startup	0.25	1200	300	25	ppmv	0.01	0.00	0.06	0.00
HCU (Sat Gas Plant)	Planned Shutdown	0.25	1200	300	25	ppmv	0.01	0.00	0.06	0.00
VGO-HDS	Area 4 Power Failure			None			0.00	0.00	0.00	0.00
HCU	Area 4 Power Failure			None			0.00	0.00	0.00	0.00
HGU	Area 4 Power Failure			None			0.00	0.00	0.00	0.00
HCU (Sat Gas Plant) - Depropanizer	Area 4 Power Failure	0.5	3000	1500	100	ppmv	0.05	0.00	0.28	0.02
HCU (Sat Gas Plant) - Debutanizer	Area 4 Power Failure	0.1	3500	350	100	ppmv	0.01	0.00	0.06	0.00
VGO-HDS	Local Power Failure			None			0.00	0.00	0.00	0.00
HGU	Area 4 Power Failure			None			0.00	0.00	0.00	0.00
HCU	Local Power Failure			None			0.00	0.00	0.00	0.00
HCU (Sat Gas Plant)	Local Power Failure	1.0	3500	3500	100	ppmv	0.12	0.01	0.65	0.05

Flare Reason	# Event/ Yr	MMBtu	tpy			
Normal Operations	1	26,280	0.89	0.07	4.86	0.34
Planned Shutdown	1	3,720	0.13	0.06	0.69	0.05
Planned Startup	1	4,584	0.16	0.03	0.85	0.06
Area 4 Power Failure	2	3,700	0.13	0.01	0.68	0.05
Local Power Failure	2	7,000	0.24	0.02	1.30	0.09
Startup after Failure	4	18,336	0.62	0.12	3.39	0.24
Total Est. Potential Flare Emissions		63,620	2.16	0.31	11.77	0.83